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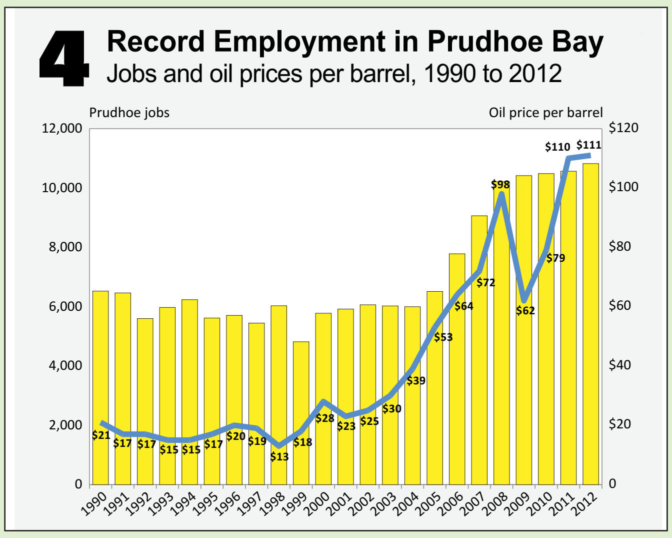
page 3 Q&A: Parnell discusses multiple North Slope gas delivery options

Employment trends



STATE OF ALASKA

Oil and gas employment at record levels, Department of Labor reports, but only 4 percent of statewide employment. See story on page 13.

Enstar plans to buy 'boil-off' gas from idling Kenai LNG facility

Enstar Natural Gas Co. is looking to connect a new supply source to its system.

Bu the natural gas won't come from existing fields, new exploration or even imports.

It will come from a hidden corner of the Kenai liquefied natural gas facility.

Just like the last scoop of peanut butter scraped from the inside wall of the jar, Enstar wants to purchase the small quantity of natural gas "produced" by warming LNG tanks.

This "boil-off gas" is an inevitable by-product of LNG storage. To preserve its liquid state, LNG must be kept in super-cooled containers. But even with good insulation, some heat leaks into tanks, causing a small portion of the LNG to revert to a gaseous state.

Enstar recently signed an agreement with ConocoPhillips, the owner of the Kenai LNG plant, to purchase boil-off gas through 2016. The sales would begin as soon as the Regulatory Commission of Alaska approves the contract and

see **'BOIL-OFF' GAS** *page 17*

Encana's new boss faces testing time; Doug Suttles a BP veteran

Encana has put a former executive of BP at the helm of its ship, which may not be in danger, but is battling severe headwinds.

DOUG SUTTLES

The board of one of North America's largest natural gas producers chose Doug Suttles, a 22-year veteran of BP who spent eight years in Alaska, as its new chief executive officer to take over from Randy Eresman who resigned six months ago.

Suttles, most recently chief operating officer of BP Exploration and Production, will move into the top floor of Western Canada's tallest and newest headquarters tower.

He will need a head for heights.

Encana has posted four straight quarterly losses, is squeezed by natural gas prices, despite signs of a rally this year, and faces disaffected shareholders.

Strategies discussion to come

Suttles told analysts June 11 he is not ready to talk about operational strategies until he has time to develop a vision for

see **NEW ENCANA BOSS** *page 14*

GOVERNMENT

Hilcorp's troubles

Alaska drilling regulators order firm to pay $115,500 for mounting violations

By WESLEY LOY
For Petroleum News

Hilcorp has paid a $115,500 civil penalty for the latest in a string of enforcement actions drilling regulators have taken against the company during its brief time as an oil and gas operator in Alaska.

The Alaska Oil and Gas Conservation Commission says Hilcorp has drawn more than a dozen enforcement actions.

The most recent case centers on an oil development well known as Soldotna Creek Unit 44-33. The Soldotna Creek unit is associated with the Hilcorp-operated Swanson River field.

Hilcorp failed to notify the AOGCC of changes to an approved permit to drill. And the company failed to test blowout prevention equipment after it was used to control the well, the commission said.

> *The bulk of the $115,500 civil penalty, or $75,000, was for "the initial violation — failure to increase the drilling fluid weight prior to milling the casing window" as required in the permit to drill.*

The agency suggested the company's vigor since arriving in Alaska had been a problem.

"The aggressiveness with which Hilcorp is moving forward with operations appears to be con-

see **HILCORP PENALTY** *page 19*

NATURAL GAS

Looking to simplify

Hilcorp evaluating the possibility of unifying its Cook Inlet gas lines

By ALAN BAILEY
Petroleum News

When Hilcorp Alaska, the company that now dominates oil and gas production in Alaska's Cook Inlet basin, took over Chevron's and Marathon's assets in the basin, the company acquired four key pipelines that deliver natural gas from Cook Inlet fields to Southcentral gas and power utilities. Now, as the dust settles from the Cook Inlet acquisitions, Hilcorp is assessing the potential to consolidate the operation of the pipelines into a single pipeline system, a move that could greatly improve pipeline efficiency, delivering cost savings to the pipeline users, Edmund Jaroch, Hilcorp Alaska's pipeline manager, told a meeting of the Regulatory Commission of Alaska on May 29.

> *And the key to the establishment of an arrangement of this type would be a "postage stamp rate" for shipping gas, Jaroch said.*

Individual pipelines

The four pipelines in question — the Cook Inlet Gas Gathering System, the Kenai Nikiski pipeline, the Kenai Kachemak pipeline and the Beluga pipeline — were all constructed at different times by different owners for different purposes. And now,

see **PIPELINE EFFICIENCY** *page 18*

NATURAL GAS

LNG tops BC to-do list

Premier Clark names veteran minister to head natural gas development portfolio

By GARY PARK
For Petroleum News

The British Columbia government has sent out a clear message it will waste no time trying to get LNG export projects on track.

SHANE LASLEY

CHRISTY CLARK

RICH COLEMAN

In unveiling her new cabinet after the May 14 election, Premier Christy Clark gave top priority to doing what she can to lock up sales contracts and using LNG as her best chance to promote job creation, resource development and economic growth.

She named Rich Coleman, former energy minister, as the head of a new Natural Gas Development Ministry and, just to reinforce the importance she attaches to LNG, deputy premier.

Clark gave Coleman a single over-riding mission: "Close those sales deals ... bring them home."

She expressed hope that some contracts will be signed this year, enabling British Columbia to achieve her goal of three operating LNG projects by 2020 and, overall, generating C$1 trillion in economic activity in 30 years.

see **BC LNG PROJECTS** *page 17*

contents

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ON THE COVER

ENVIRONMENT & SAFETY

FINANCE & ECONOMY

GOVERNMENT

INTERNATIONAL

LAND & LEASING

NATURAL GAS

PIPELINES & DOWNSTREAM

● GOVERNMENT

Parnell: Multiple gas options in play

LNG project under way to provide natural gas to Interior; AGDC working in-state line; next benchmark up for large diameter line

By STEVE QUINN
For Petroleum News

Oil taxes may have grabbed more headlines, but advancing a natural gas pipeline project and marketing North Slope gas never fell off the draft board in Gov. Sean Parnell's office.

Last fall, Parnell traveled to Japan and Korea to tout the state's export prospects, highlighting decades of reliable Cook Inlet deliveries to Japan.

Later that fall, Parnell proposed a $365 million financing package to deliver North Slope natural gas to Fairbanks and other Interior communities. With the Legislature's backing, he advanced this project (Senate Bill 23) and an in-state line (House Bill 4). Both bills received Parnell's signature within the last month.

For the second straight year, he kicked off the legislative session by outlining expectations to advance a large-diameter natural gas pipeline.

News of two benchmarks for North Slope leaseholders ExxonMobil, ConocoPhillips and BP, and pipeline company TransCanada was expected no later June 20.

Those benchmarks are: a commitment to a full summer of field season work and enter the pre-FEED stage, also known as pre-front-end engineering and design, which means, Parnell says, committing hundreds of millions of "private sector" dollars.

Parnell spoke with Petroleum News about progress made toward marketing North Slope gas and advancing a pipeline project. This is the second of two-parts.

Petroleum News: You've has some fun signing some natural gas bills, starting with HB 4. What do you see as the value in advancing a natural gas pipeline project?

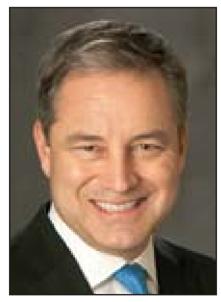
Parnell: Well, I think it's at least two fold. The AGDC (Alaska Gasline Development Corp.) can carry the state's interest in a 42-inch line with the producers or it can continue moving with other parties on its own line. That's just the benefit of HB 4. It's given us the opportunity to get Alaska's gas to Alaskans. It's made it flexible enough to achieve it one way or the other.

Petroleum News: On the shorter term, your LNG trucking proposal from the fall is coming to fruition with SB 23. Is this what you had in mind back in the fall?

Parnell: Absolutely. For the first time in Alaska history, North Slope gas will be commercialized for the benefit of Alaskans, particularly those in the Interior. Secondly, this Interior energy project will provide an energy distribution system not just for the near-term trucking solution, but it provides a distribution system for when a gas line is completed through Alaska.

Petroleum News: So would these two become compatible in any way?

Parnell: They already are. SB 23 authorizes financing for a gas distribution system. That distribution has to be in place for Fairbanks residents, for example, and other Interior residents, to benefit from a gas line. So they are already complementary.


GOV. SEAN PARNELL

Petroleum News: Let's go back a year and a half. How has the Point Thomson agreement paid off toward a pipeline project? It's pretty well accepted that Point Thomson is critical to advancing a large-diameter line.

Parnell: So far it's hundreds of new construction jobs at the field. Next we should be seeing more liquids production from Point Thomson for the peoples' benefit by 2016. Finally, there is significant value in positioning that field to feed a large-diameter gas line. There is more going on than people appreciate it. You should call the companies and ask for employment figures. I think because it's on the east side of the North Slope — out of sight, out of mind for most. Unless you're flying over that area, you wouldn't know how much activity is going on in that area. It's been an economic boom for Alaska companies when it comes to construction and trucking and contractors.

Petroleum News: Can you elaborate on what you envision with both projects possibly coming together? I know there have been some criticisms directed toward these prospects.

Parnell: I think too many people get stuck on what they see. I think what they see is AGDC working one project — the 36-inch line project — and they see the producers and TransCanada meeting benchmarks that I set in my State-of-the-State addresses under an AGIA framework in another project. What is seen are really two projects. What I envision is one project for Alaskans. Rather than seeing what is, I see what can be. Here's what I mean by that. If the producers and TransCanada meet the benchmarks I set, then I envision AGDC carrying Alaska's interest in the 42-inch line. If the producers and TransCanada do not meet those benchmarks, then I see AGDC moving forward with its own plans for a line. That's, in short, the framework we have.

Petroleum News: Do you believe there has been enough movement for people who have been hearing about a natural gas pipeline for the last four decades to feel optimistic?

Parnell: When I came into office, Point Thomson had not been resolved and the companies were not aligned on negotiating on a project together. Where we are today is what we have now is a corporation that is empowered to carry the state's interest on a gas line and capitalized to carry that interest. We have four companies — Conoco, BP, TransCanada and Exxon — negotiating their commercial terms, and to me that's progress. But I understand. Alaskans and I are frustrated as can be at not having gas at this point. But I also can look back over the last three years and see progress and see that we're in a historic place and the state has never been positioned better to move forward on a gas line.

Q AND A

Petroleum News: At some point there will probably have to be fiscal term negotiations. Has SB 21 taken care of some of that or will there be more items to bring to the table?

Parnell: SB 21 resolved the competitiveness of the oil tax system. Anybody who runs gas through a gas line will want some different gas tax terms. What I've said multiple times is that we as the state will take commensurate, proportionate steps with companies that want to build a gas line. Meaning, don't expect billions of dollars in tax changes unless you are willing to put billions of dollars on the table for a project.

For instance, back in the day of the Stranded Gas Development Act, the producers and the state had agreed on a framework for gas fiscals and certainty over a long period of time, but the producers had made no commitment commensurate with what the state had made, and I will not put the state in that situation. Instead, my view is this: the state has already committed up to $500 million under AGIA framework for reimbursing the licensee there. The state has already committed over $300 million to capitalize AGDC to carry the state's interest in a line. With hundreds of millions of dollars in value already on the table from the state I am looking for the companies to put forth hundreds of millions of dollars of effort. That's what I mean by commensurate proportionate steps.

This is a different situation than 10 years ago when companies were asking for fiscal certainty but then could come back for a second bite of the apple because they hadn't made a specific commitment to sanction a project. Lots of work to do there yet, but we're making progress.

see **PARNELL Q&A** page 15

LAND & LEASING

MGM backs off Mackenzie Delta

Faced with meeting an early C$6.3 million work-spending commitment to retain its exploration licenses in the Mackenzie Delta region of the Northwest Territories and little evidence that natural gas from the Arctic has any hope of reaching southern Canadian and U.S. markets, MGM Energy has headed for the exit.

The Calgary-based junior explorer was the last company to continue drilling while the majors had shelved their exploration plans as hopes for the Mackenzie Gas Project to initially deliver 800 million to 1.2 billion cubic feet per day to customers started to dwindle.

The Imperial Oil-headed MGP venture went through a drawn-out regulatory process, a delay that saw the project overhauled by the rapid emergence of technology-driven shale gas prospects and a slump in commodity prices.

Four licenses surrendered

MGM has surrendered four exploration licenses that were due to expire in January 2016, failing which it was due to make a payment of C$6.3 million in June, and con-

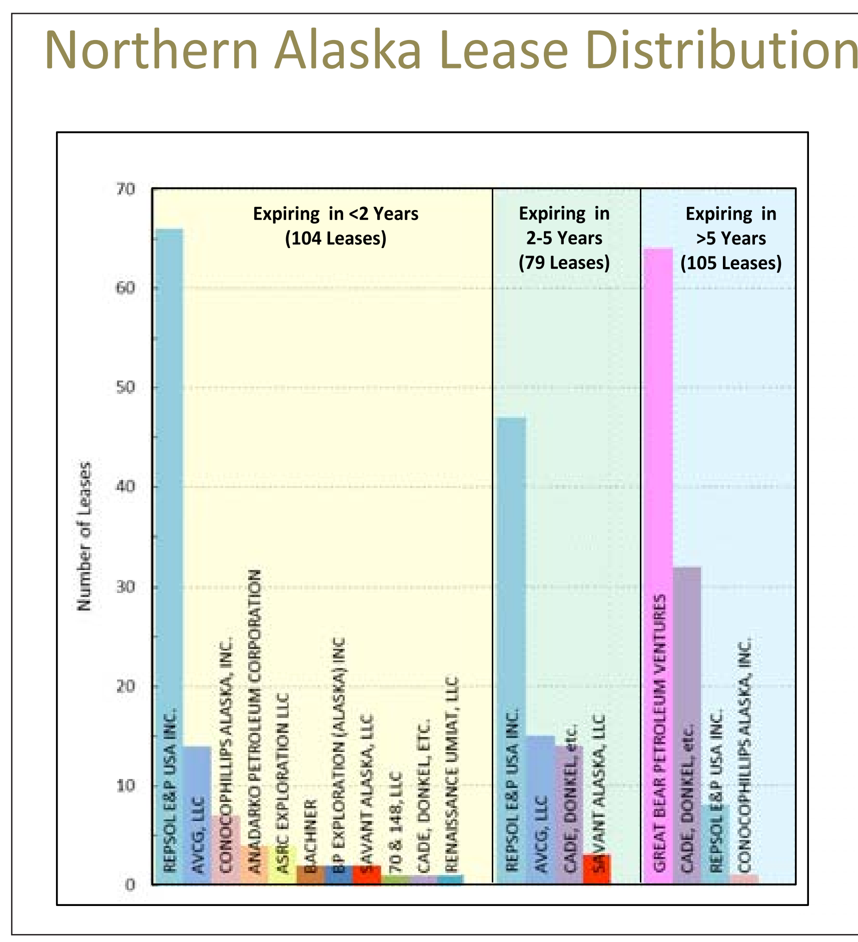
see **MAC LICENSES** *page 6*

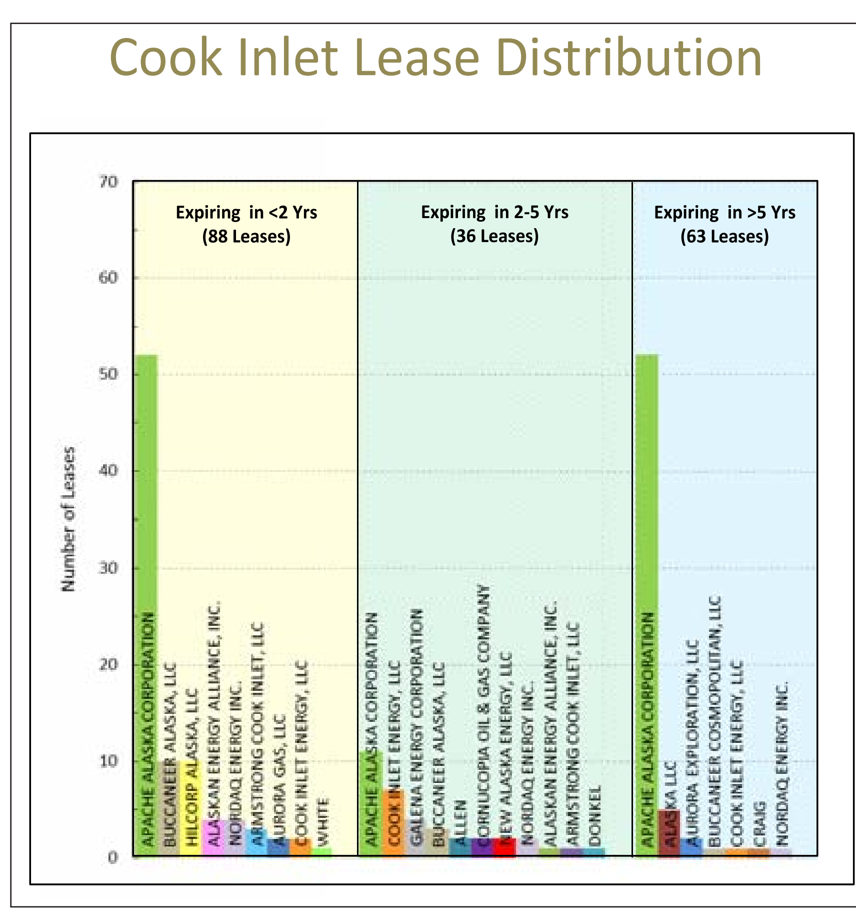
CORRECTION

Charts re-run

The charts accompanying the "New law gives operators a chance for one-time lease term extension" story in the June 9 issue of Petroleum News did not print correctly.

Below are the charts as they should have appeared.





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● PIPELINES & DOWNSTREAM

Alberta premier chases all options

Ready to see pipeline resolution with BC, but not to share oil sands royalties, not prepared to wait; sales pitch to New Brunswick

By GARY PARK

For Petroleum News

Alberta Premier Alison Redford has expressed hope that she can patch up differences with her British Columbia counterpart Christy Clark, but not to the extent of supporting tolls on pipelines from the oil sands to the Pacific Coast.

British Columbia Environment Minister Terry Lake told reporters during an Alberta visit earlier in June that if Enbridge's Northern Gateway was to proceed, his government might consider putting a toll on Alberta bitumen crossing British Columbia to increase its revenue share of the project.

ALISON REDFORD

"Certainly we would want to make sure there's a toll that looks after environmental protection, to pay for the regulatory regime and have a spill response fund in place," he said.

However, talk of a border tax on oil moving from Alberta to British Columbia could trigger threats of a retaliatory tax on natural gas moving eastward from British Columbia.

Redford, without indicating whether she is open to compromise with British Columbia, has never shifted from her hard-line stance that sharing Alberta's oil sands royalties is "just a non-starter."

Redford said the energy industry is "fully on-side" with a west-to-east pipeline and Canadian Prime Minister Stephen Harper met with the industry in Calgary two months ago to enlist support for the proposal.

Redford: 'good discussions'

Redford said she and Clark have had "some very good discussions with respect to Gateway" since the British Columbia election May 14, is certain she can deal in a straight-up manner with Clark and anticipates meeting later in June to discuss energy issues.

She is also anxious to ensure that the oil and gas industry can have "confidence in a long-term regulatory framework where politics won't be played. Otherwise that just shakes investor confidence."

Until then, any talk of tolls is "very speculative. I think that at this point getting into specific proposals or counter proposals is not where we need to be."

"It is fundamental for B.C. and Alberta to work together to ensure that we continue to be the economic engine of Canada."
—Alberta Premier Alison Redford

Even so, she understands Clark's desire to build economic development across British Columbia.

"It is fundamental for B.C. and Alberta to work together to ensure that we continue to be the economic engine of Canada," she said.

Redford also noted that Enbridge and the British Columbia government plan to hold their own negotiations.

Enbridge remains confident

After many weeks of saying nothing publicly during the B.C. election campaign and a heated public debate over Northern Gateway, Enbridge Chief Executive Officer Al Monaco told reporters after a National Energy Board pipeline safety forum that he remains "confident (Northern Gateway) will go, but I'm not taking it for granted. We have a lot of work to do."

He gave priority to meeting with the British Columbia government and resolving its doubts over the pipeline because of unanswered environmental questions.

"I think the British Columbia position is pretty much what they've stated, which is they want to see more information," Monaco said.

He said Enbridge shares the concerns of the Clark government around certain issues.

"We're hopeful that eventually we'll be able to sit down with them" and provide more information on safety plans by the time regulators hear final arguments later in June, Monaco said, adding that a lot of issues can't be resolved until "detailed design" work starts.

Redford has also made it clear she is not counting exclusively on an agreement with the British Columbia government that would open the door to Northern Gateway and Kinder Morgan's Trans Mountain expansion — combined projects to provide access to tidewater for an additional 1.1 million barrels per day of oil sands crude.

Talking to New Brunswick

With uncertainty hanging over pipelines from Alberta to the British Columbia coast and the U.S. Gulf Coast, Redford travelled to New Brunswick on June 7 to tour the 300,000 bpd Irving Oil refinery in Saint John and speak to the provincial legislature about the merits of TransCanada's Energy East project which could see Canadian crude shipped to the Irving facility.

To a standing ovation from the New Brunswick legislature, Redford said there is no reason why Canada cannot handle both economic and environmental issues and build pipelines that benefit all Canadians.

"It's not an either/or conversation," she said. "We've always done a very good job in Canada of being able to balance (environmental and economic) interests and I think we can continue to do that."

New Brunswick Premier David Alward said the TransCanada proposal to move 500,000-850,000 bpd from Western Canada to Eastern and Atlantic Canada is gaining support from other premiers because it "makes economic sense for Canada. Where there are pipelines there are opportunities for growth and prosperity."

Redford said the energy industry is "fully on-side" with a west-to-east pipeline and Canadian Prime Minister Stephen Harper met with the industry in Calgary two months ago to enlist support for the proposal.

Questions on path to peace

Not everyone is certain that Alberta and British Columbia will find an easy path to peace.

Robert Johnston, director of global energy for the Eurasia Group, said in a research note that Clark's determination to get "value-added investment and job creation on the back of oil sands pipelines" sets the stage for tough negotiations.

He said Alberta's refinery industry and trade unions want spending on upgraders and refineries to occur in the Edmonton area, "a prospect that would do little to appease Clark."

But Johnston doubts that the 500,000 bpd refinery proposed for Kitimat by newspaper publisher David Black would provide the answer if it has to compete for construction and materials with LNG projects.

He suggested the current Kitimat plan is "likely too large as its output would exceed the needs of local markets to compete in Asia-Pacific export markets, where complex refineries in China and India are already out-competing incumbents in markets like Japan and Australia."

Johnston also said that a British Columbia refinery would likely need backing from the British Columbia, Alberta and Canadian governments, along with an Asian investor.

He said that could involve the use of government pension funds, although those funds are "independent and would have to have a clear investment motive in any given project," while Chinese financial support would be challenged by China's state-owned domestic refining and upgrading plants "where they can manage costs more effectively." ●

Contact Gary Park through publisher@petroleumnews.com

● GOVERNMENT

ConocoPhillips faces $45,000 penalty

Alaska drilling regulators cite violations surrounding a well in the company-operated Kuparuk River unit; hearing set for Aug. 20

By WESLEY LOY
For Petroleum News

ConocoPhillips Alaska Inc. is facing a $45,000 civil penalty for alleged violations at a well in the Kuparuk River unit on the North Slope.

The company has asked the Alaska Oil and Gas Conservation Commission, which regulates drilling, to reconsider its decision to impose the penalty.

As a result, the commission has scheduled a public hearing for 9 a.m. Aug. 20 in Anchorage.

Two violations alleged

The commission says ConocoPhillips, which operates the huge Kuparuk oil field, missed the deadline for a mechanical integrity test and failed to report "pressure communication" in well KRU 3Q-16 by the next working day.

"We expect to resolve this matter at the hearing in August," company spokeswoman Natalie Lowman told Petroleum News on June 12.

The commission's proposed order indicates KRU 3Q-16 is an injection well. It says the well was due for a mechanical integrity test no later than Sept. 25, 2012.

"By email dated November 13, 2012 CPAI notified the AOGCC that KRU 3Q-16 was returned to injection on August 22, 2012 and ceased taking injection November 1, 2012, and was shut in November 13, 2012," the order says.

Every day from Sept. 26 through Nov. 12 was a violation, the order says.

Further, graphical plots of the well's tubing, inner annulus and outer annulus pressures indicated "significant pressure anomalies" that were not reported to the AOGCC, the order says.

Mitigating factors

The commission said it considered certain factors in determining the appropriate penalty for ConocoPhillips.

The civil penalty was decreased from the maximums provided by statute, in part due to the company's "general history of satisfactory compliance and practices."

Other mitigating circumstances included "the lack of actual threat to public health or the environment," and the company's shut-in of the well once it determined KRU 3Q-16 was out of compliance.

The commission is proposing a number of corrective actions. Within two weeks of the order becoming final, ConocoPhillips would have to provide "a detailed description of its Underground Injection Control regulatory compliance program."

The company also would have to provide details of its tracking system for determining when mechanical integrity tests are required. And ConocoPhillips would have to provide a root cause analysis addressing the violations.

At an informal conference, the company indicated it had performed a root cause analysis and "outlined the changes it had made in order to avoid similar violations in the future," the proposed order says.

But the company didn't share the analysis with the AOGCC. ●

Contact Wesley Loy at wloy@petroleumnews.com

● GOVERNMENT

Another CD-5 suit filed against Corps

Center for Biological Diversity claims violation of Clean Water Act, Endangered Species Act, National Environmental Policy Act

By KRISTEN NELSON
Petroleum News

The approval by the U.S. Army Corps of Engineers of ConocoPhillips Alaska's CD-5 development in the National Petroleum Reserve-Alaska has drawn another court challenge. The Center for Biological Diversity said in a June 5 statement that it was challenging the agency's approval of the development.

"We're deeply concerned that this project could kick the door open for industrial development in the reserve's priceless habitat for caribou, birds and other wildlife," Deidre McDonnell, a senior attorney with the Center for Biological Diversity, said in a statement.

An earlier suit, filed against the Corps in late February by Trustees for Alaska on behalf of seven residents of Nuiqsut, subsistence hunters and fishers, cited plaintiffs' concern that the development would harm their way of life.

Drill site, bridge, road

CD-5, or Alpine West, includes a new drill site in NPR-A, a bridge across the Nigliq Channel of the Colville River carrying a crude oil pipeline from CD-5 to the Alpine field processing facilities and three smaller bridges. The plan requires fill in 58.5 acres, including six miles of road.

The Corps issued a Section 404 permit for Alpine satellite CD-5 in December 2011, but that was after denying that permit in 2010 based on objections from the U.S. Fish and Wildlife Service and the U.S. Environmental Protection Agency, both of whom opposed the bridge over the Nigliq Channel. In early 2010 the Corps said there were less environmental damaging practicable alternatives, specifically a pipeline under the Nigliq Channel using horizontal directional drilling.

The State of Alaska and the state's congressional delegation objected to the Corps' 2010 denial and ConocoPhillips appealed the decision.

In the December 2011 approval the Corps said the ConocoPhillips' proposal "with special conditions" had been determined to be the least environmentally damaging practicable alternative, "based on other environmental consequences of pipeline monitoring, leak detection, and spill response." The Corps also said ConocoPhillips' proposal for road access to CD-5 "is the only alternative that would provide year round spill response access."

LEDPA dispute

In its suit the Center for Biological Diversity argues that ConocoPhillips' plan "was not the least environmentally damaging practicable alternative" (LEDPA). In reversing its original decision, the Corps in its "decision green lights the first oil development within the National Petroleum Reserve-Alaska (Reserve) and would connect the Reserve with existing oil infrastructure outside its boundaries," the complaint states.

Plaintiffs call for a supplemental environmental impact statement, arguing that

see **CD-5 LAWSUIT** page 7

continued from page 4

MAC LICENSES

solidated another license.

John Hogg, MGM vice president of exploration and operations, told the Canadian Broadcasting Corp. that his company "saw little potential for the Mackenzie gas pipeline to be back on stream before those licenses expire" and without a pipeline there was no reason to drill for oil.

"It just doesn't make sense to not have the infrastructure to get your product out," he said.

Less troubled was Mayor Merven Gruden of Tuktoyaktuk, NWT, who said he was "not too worried" by MGM's decision,

He said that exploration being developed for the Beaufort Sea by Imperial Oil, ExxonMobil, BP and ConocoPhillips meant that region would still go forward.

Activity is also intense on the Canol shale region of the Central Mackenzie Valley, giving the NWT some hope of resource development.

—GARY PARK

Contact Gary Park through publisher@petroleumnews.com

● GOVERNMENT

Sally Jewell makes ANWR stance clear

Interior secretary cites Obama opposition to oil exploration, sticks to controversial funding proposal for 'legacy well' cleanup

By WESLEY LOY
For Petroleum News

In case anyone is still unsure where the Obama administration stands on drilling in the Arctic National Wildlife Refuge, please refer to newly installed Interior Secretary Sally Jewell's recent congressional testimony.


SALLY JEWELL

"The president has made it clear that it is not part of his agenda to do oil and gas exploration in the Arctic National Wildlife Refuge, and I support that position," she said.

Jewell made the statement under questioning from U.S. Sen. Lisa Murkowski, R-Alaska, during a June 6 hearing of the Senate Energy and Natural Resources Committee. Murkowski is the committee's top-ranking minority member.

The secretary's testimony comes as an Interior agency, the U.S. Fish and Wildlife Service, prepares to finalize a new management plan for ANWR.

To the dismay of Murkowski and other Alaska elected officials, the draft version of that plan didn't include an alternative for allowing oil and gas exploration on ANWR's highly prospective coastal plain.

The draft, however, did include options to convert the coastal plain to wilderness, which effectively would ban exploration permanently in the area.

Murkowski, during the hearing, said it seemed inconsistent to include wilderness alternatives and not an oil and gas alternative, because an affirmative act of Congress would be required either way.

The senator cited federal regulations she said require the Interior Department to analyze all reasonable alternatives, and she urged Jewell to take another look at the ANWR management plan before releasing the final version.

Legacy well cleanup

Murkowski and Jewell also had an interesting exchange on the so-called legacy wells on Alaska's North Slope.

The legacy wells are dozens of test wells the U.S. Geological Survey and the Navy drilled between 1944 and 1982 in or near what today is called the National Petroleum Reserve-Alaska. Another Interior agency, the Bureau of Land Management, shepherds the vast NPR-A.

Murkowski and other state officials say the federal government has neglected the legacy sites, where some wells remain unplugged and surface areas are junk-strewn and potentially contaminated.

see ANWR STANCE page 14

ENVIRONMENT & SAFETY

Court declines global warming case

In a May 20 ruling the U.S. Supreme Court declined to hear a case in which the Chukchi Sea coastal village of Kivalina had sued multiple energy and utility companies for the impacts of global warming from fossil fuel use. The village claimed that recent coastal erosion threatening the village's survival is a direct consequence of human-induced global warming. Companies sued included ExxonMobil, BP, Chevron and ConocoPhillips.

According to court documents the village alleged that carbon dioxide produced by energy company actions has caused the Earth's atmosphere to warm. Consequent loss of sea ice has left the village's land exposed to massive erosion from storms, the village claimed. The village also claimed that rising sea levels as a consequence of the expansion of the ocean waters and the melting of glaciers and ice caps is destroying Kivalina's land.

The California District Court originally dismissed the claim on the grounds that dealing with climate change is a political issue and because the court found that Kivalina had not demonstrated a causal connection between the energy companies' actions and damage to the village. The case was appealed to the U.S. Court of Appeals for the 9th Circuit, which found that the federal Clean Air Act and consequent actions of the Environmental Protection Agency to address greenhouse gas emissions supersede Kivalina's ability to make a statutory claim against the energy companies as a "public nuisance."

By declining to take the case, the Supreme Court has presumably in effect upheld the 9th Circuit's position.

Although there has been a stream of court cases in recent years relating to climate change, the Kivalina case is somewhat unusual in that it has involved litigation under common law. Most cases have involved appealing government agency decisions under legislative schemes such as the National Environmental Policy Act.

—ALAN BAILEY

continued from page 6

CD-5 LAWSUIT

"the Corps failed to conduct a site-specific analysis as required by the National Environmental Policy Act (NEPA), instead relying on a nearly nine-year-old analysis conducted before ConocoPhillips made its current proposal." The Center for Biological Diversity also said the Corps failed to consult with the National Marine Fisheries Service to ensure the project would not jeopardize whales and seals listed under the Endangered Species Act.

The Center for Biological Diversity is a national nonprofit conservation organization; it said in its filing that it has been actively involved in protecting Alaska's wildlife since the early 1990s, and has been involved in protection of wildlife resources in NPR-A since 1998. ●

Contact Kristen Nelson at knelson@petroleumnews.com

● NATURAL GAS

LNG industry eyes transportation market

Viva la revolution: Switches in transportation fuels occur and they can occur quickly, such as the switch to diesel by long-haul trucks

By BILL WHITE

Researcher/writer for the Office of the Federal Coordinator

Transportation revolutions do occur. And they can get traction quickly.

At the LNG 17 conference, two speakers recounted stories of a new fuel overthrowing an older, long-entrenched one thanks to compelling economics and new technology.

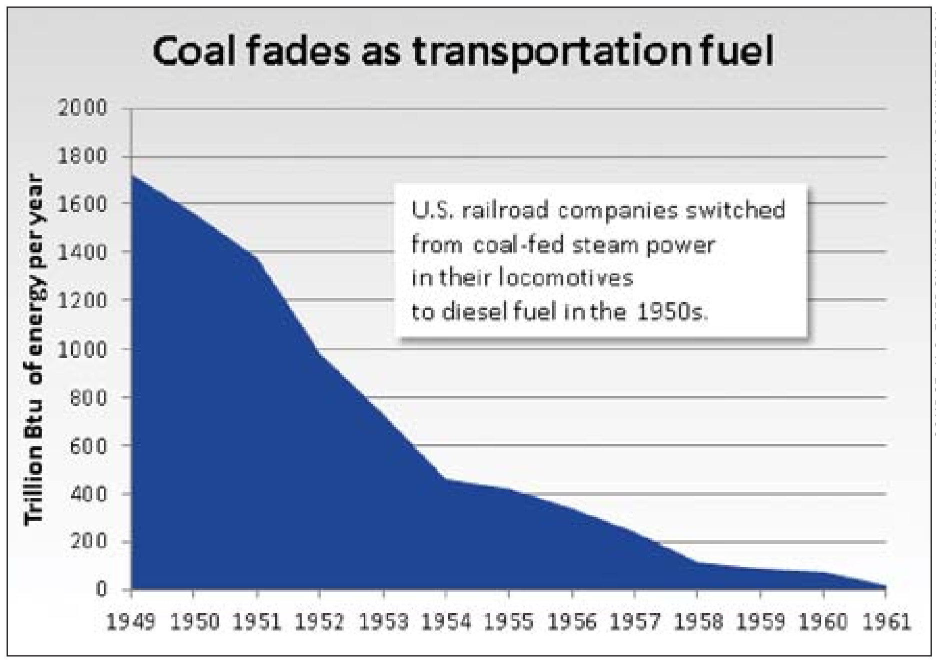
Long-haul trucks switch to diesel

Before the 1950s, U.S. highway trucks ran on gasoline. Diesel was around and had been tested, but it was more expensive, less available and heavier, said Paul Blomerus, who works for Westport Innovations Inc., a global leader in natural gas engines.

BILL WHITE

But in the 1950s and 1960s, more efficient engines hit the market and diesel became less expensive and more plentiful.

"The market share of diesel trucks grew from 10-15 percent in 1950 to 100 percent by the 1980s. Even though diesel-powered trucks cost more and were heavier than gasoline-powered trucks, the economic case provided by the increased productivity and lower fuel costs was overwhelming," Blomerus said in a paper he co-authored with Westport colleague Patric Oulette for the conference.



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION

Power plants embrace natural gas

"Recently, an even more rapid transition is taking place in the electricity generation industry, from coal to natural gas," Blomerus and Oulette wrote.

Coal has been the dominant fuel source for electrical generation for decades. Coal is relatively inexpensive. But natural gas is a cleaner and more energy-efficient fossil fuel.

A new technology In the 1980s helped improve natural gas economics as a power-plant fuel. So-called combined-cycle generation works this way: Gas powers a turbine to make electricity, and the hot exhaust from this process powers a steam turbine also to make electricity. Power utilities using combined-cycle generation get a two-fer out of natural gas, making the fuel more appealing.

In 1986, just 6 percent of new-build power plants burned natural gas. By 2000, 96 percent of new power plants were built for natural gas, Blomerus told the conference.

Favorable economics plus technology that works equals a rapid transition, he said. The same phenomenon has happened in recent years as trash-hauling companies have switched to CNG-fueled trucks, he said. Westport has teamed with Cummins Inc. to develop efficient natural gas-fueled engines.

Railroads move to diesel

John Hatley is Americas vice president for ship power at Wartsila, a Finnish maker of ship engines. He discussed how in just 13 years, during the 1940s and 1950s, almost the entire North American railroad industry abandoned coal-fired steam locomotives in favor of diesel fuel.

The economic benefits of diesel overpowered coal for railroad companies after new engines improved the efficiency of diesel fuel, he said.

1 2 SERIES

Will a new revolution led by LNG dethrone diesel? Hatley thinks so. LNG as a locomotive fuel is starting to show the same advantages over diesel that diesel showed over coal, he said. Trains will switch to LNG locomotives even faster than they embraced diesel six decades ago, he predicted.

Steam ships displace sails

As for ships, Hatley noted, coal-fueled steam ships took 85 years to knock sails out of the game. Eighty-five years? Well, Hatley said, it took a while to improve steam engines so they stopped blowing up and sinking vessels.

It won't take that long for LNG to displace diesel as a ship fuel, he said. "It's a small leap. The technology is available and proven."

Not all revolutions result in a new regime, however.

In the 1980s and early 1990s, the Soviet Union dabbled with LNG as an aircraft fuel. A converted Tupolev Tu-155 jet (similar to a Boeing 727) took flight in January 1989 with LNG powering one of its three engines, International Gas magazine said in a recent feature on LNG as a transportation fuel.

"The aircraft made a visit to Nice for LNG 9 later that year and to Berlin for the 18th World Gas Conference," the magazine said.

But the pilot project got grounded when the Soviet Union collapsed.

A 360-degree approach

Shell hopes it has the right strategy to crack the chicken-or-egg puzzle: Simultaneously develop all facets of an LNG transportation-fuel industry.

First, Shell will supply the LNG.

Most liquefaction plants are massive, multibillion-dollar factories built to supply huge volumes for the export market. A niche transportation user would be challenged to get such a plant to even return its phone calls.

So Shell developed a Shetland pony version of an LNG plant, one more suited to serving small-scale markets. Shell's Moveable Modular Liquefaction System aims "to deliver LNG on a smaller scale than would be economic and convenient for use in the transport sector," James Burns, general manager for Shell LNG for Transport, Americas, said at the LNG 17 conference. Shell's first mini-LNG plant is under construction outside Calgary.

To give a sense of the difference in scale, consider the Alaska LNG export project under consideration by ExxonMobil, BP, ConocoPhillips and TransCanada. If built as currently conceived, the plant would export 15 million to 18 million metric tons per year, or 2 billion to 2.4 billion cubic feet a day. The Shell Alberta plant's capacity will be 250,000 metric tons per year, or 33 million

see LNG MARKETS page 9

continued from page 8

LNG MARKETS

cubic feet a day. (GE has developed an even smaller LNG plant.)

For other parts of the value chain, Shell is collaborating with TravelCenters to sell fuel at truck stops, with Volvo to make LNG-fueled trucks, GE to develop locomotives that can run on both diesel and LNG, and Wartsila to speed deployment of LNG-fueled ship engines.

GDF Suez is taking a similar tack in Europe via subsidiary GNVERT (translation "green natural gas"). Gas will come from several LNG importing terminals in Europe. GDF is working with truck makers IVECO and Volvo to develop and test vehicles. Its first LNG refueling station is under construction outside Paris. More are planned along major border-crossing highways. GDF will design, build and finance, if necessary, the refueling stations, said Hubert, GNVERT's chief executive.

"Our solution is to solve (the chicken-or-egg problem) for all transportation companies," Hubert said.

Jeffrey P. Beale, president of U.S.-based LNG consulting firm CH-IV International, told the Houston conference an already-existing source of LNG should be considered. U.S. utilities built over 50 small LNG plants during the 1960 and 1970s. The plants were designed to give the utilities extra natural gas during peak winter demand.

But many of these so-called peak shavers are idle or under used because pipeline gas is more readily available to utilities now, Beale said. The transportation industry should look to these plants as a source of LNG fuel for long-haul trucks and ships, he said.

China's LNG initiative

China's love affair with small-scale LNG plants resembles what happened in North America 40 to 50 years ago.

China's first commercial LNG plant started up in 2001. By the end of 2012, about 60 plants had been built. Seventeen started in 2012 alone. A typical size is 700,000 to 10 million cubic feet a day, according to the China LNG Association. That's between one and 10 cargoes a day, as the average 40-foot-long tanker truck can carry about 1 million cubic feet of gas as LNG.

Motivated in part by serious urban air pollution, the Chinese government last year issued a new Natural Gas Utilization Policy. It calls for more dual-fuel cars and LNG vehicles, plus LNG or dual-fuel ships on rivers, lakes and along the country's coast.

The number of LNG filling stations doubled in 2012, reaching 385, mostly located near coastal cities, the LNG association said.

A variety of reports peg the cost of converting a long-haul truck to LNG at up to $100,000. While UPS and a few other trucking companies have embraced LNG fuel, most others are leery.

Winning economics?

It's unclear whether LNG fuel can leverage its two most winning features — a cost advantage and less pollution — into a sizeable market share in the transportation industry.

On price, LNG is about $1.50 a gallon cheaper than diesel at today's oil and natural gas costs in North America. Clean Energy says its LNG price in California averaged $2.91 per gallon of diesel equivalent last year, compared with a diesel fuel average of $4.23. In Asia, LNG might not have much price advantage because, unlike in North America, so much LNG is sold there at oil-linked prices.

On pollution, new International Maritime Organization rules strictly limit sulfur oxide emissions by ships. Ordinary diesel and heavy fuel oil emit a lot of sulfur oxide when burned. LNG has virtually zero SOx emissions.

In two parts of the world — along the U.S. and Canadian coasts, and in the Baltic and North seas as well as the English Channel — the SOx limits are ultra-strict. As of 2010, the sulfur content of marine fuel in these "emission control areas" must be 1 percent or lower. As of 2015, the sulfur content must be 0.1 percent or lower.

These limits explain Totem Ocean Trailer's conversion of its Alaska fleet to LNG as well as Shell's move to make LNG for ships plying the Great Lakes, Mississippi River and Gulf of Mexico coast.

For ships sailing on the open ocean and along other coasts, the sulfur content of their fuel can be 3.5 percent now, a limit that will shrink to 0.5 percent in either 2020 or 2025, depending on cleaner marine-fuel availability.

But neither of these LNG advantages — lower price and pollution — come for free.

Costly conversions

For trucks, the build-out of LNG fueling stations has only just begun. For ships, northern Europe has a few LNG refueling ports and a couple other ports there are maneuvering for position. Singapore also hopes to become a refueling hub. But that's about it.

Further, conversion costs are high.

The Staten Island Ferry system is using a $2.3 million federal grant to help pay for converting one ferry to natural gas, according to the American Gas Association.

American Clean Skies in 2012 estimated the cost of converting a medium-sized tug at $7 million, and a Great Lakes bulk carrier at $24 million.

A variety of reports peg the cost of converting a long-haul truck to LNG at up to $100,000. While UPS and a few other trucking companies have embraced LNG fuel, most others are leery.

"The upfront cost is too high," one trucking executive told Reuters. "We can't make the economics work."

At the LNG 17 conference, Paul Blomerus of Westport Innovations flashed a slide on the screen showing that if the oil, mining, rail and marine industries were consuming LNG instead of diesel, global LNG demand would grow by one-third, or 80 million metric tons a year (almost 11 billion cubic feet a day).

There's a boisterous debate about how much of that opportunity space LNG can win.

"LNG has become a credible challenger to oil products for marine and heavy-duty transportation," three market analysts for French oil company Total said in a paper delivered at LNG 17. "However, the lack of infrastructure for LNG retailing and the limited number of LNG-fueled vehicles creates a challenge. Therefore, the emergence of an LNG market for marine and heavy-duty transport depends on powerful drivers being in place to break the stalemate."

For just marine fuels, forecasts range from 700,000 to 66 million metric tons of LNG demand by 2025, Frederick Adamchak of consultancy Poten & Partners told the LNG 17 crowd. He called it a challenge to get ship owners, ship builders, ports, suppliers and others all moving in the same direction at the same time.

The old chicken-or-egg riddle.

"Someone has to take the initiative," he said.

Poten's forecast for 2025: 8.5 million metric tons. Just as turning a ship takes time, getting ship owners to adopt a new fuel occurs gradually, he said.

Poten's analysis of the market assumes only newly built ships will use LNG. Conversion of existing ships is expensive and technically challenging. It also keeps ships in port instead of at sea making money while the conversion occurs, Adamchak said. Owners of existing ships likely will opt to burn a low-sulfur brew of diesel, which is more expensive than regular diesel, or install pollution scrubbers on smokestacks.

Last year, a Lloyd's Register study also concluded LNG's best bet would be with new construction. And LNG might get just a toehold there.

Lloyd's is one of the big international organizations that establishes technical standards for ship construction and operations. In its report, Lloyd's predicted just 4 percent of new ships delivered by 2025 — 653 ships total — would use LNG fuel.

LNG's best bet is as a fuel for container ships, cruise ships or oil tankers, Lloyd's said.

At LNG 17, Hatley of Wartsila took the long view about LNG's future as a marine fuel: "Probably within 30 to 40 years a dramatic change will occur." ●

Part 1 of this story appeared in the June 9 issue.

Editor's note: This is a reprint from the Office of the Federal Coordinator, Alaska Natural Gas Transportation Projects, online at www.arcticgas.gov/lng-industry-eyes-transportation-market.

● GOVERNMENT

Kulluk hearing brought out key issues

Testimony to Coast Guard provided fascinating insights into the circumstances surrounding the grounding of Shell's drilling rig

U.S. COAST GUARD

By ALAN BAILEY
Petroleum News

The U.S. Coast Guard has yet to publish the results of its investigation into the circumstances surrounding the Dec. 31 grounding of the Kulluk, Shell's Arctic floating drilling platform. But a nine-day public hearing in Anchorage, gathering testimony for the investigation, provided some fascinating insights into the events that led to the Kulluk ending up on the shore of a remote island on the northern coast of the Gulf of Alaska.

Chain of events

The broad outline of that chain of events was already well known. On Dec. 27, 2012, during a tow from Dutch Harbor in the Aleutian Islands to the U.S. West Coast, the towline parted between the Kulluk and the vessel towing it, Shell's anchor handling vessel, the Aiviq. An emergency towline was subsequently hooked up between the two vessels. But early on Dec. 28 the Aiviq lost power in all four of its engines. Later that day the Guardsman, a support vessel, arrived on scene and took the Aiviq and Kulluk under tow in a tandem configuration.

On the morning of Dec. 29 the tow from the Guardsman failed. By noon of that day, following repairs to the Aiviq's engines, three of the engines were back in operation. But by that time the Nanuq, Shell's Arctic oil spill response vessel had arrived on scene and, together with the Aiviq, succeeded in bringing the Kulluk under tow again.

But with the weather worsening towards a severe storm, eventually with a 55- to 64-knot gale and 35- to 45-foot seas, vessels attempting to tow the Kulluk to safety experienced multiple towline failures and were ultimately unable to pull the Kulluk against the wind. The drilling platform ran aground on the evening of Dec. 31.

Detailed testimony presented at the Coast Guard hearing, as reported in a series of articles in the Anchorage Daily News, provided insights into various factors relating to the grounding.

Moved for maintenance

Shell has said that it needed to move the Kulluk south from Alaska for maintenance work in a West Coast shipyard in preparation for drilling in the Beaufort Sea in 2013 (following the Kulluk grounding the company postponed its drilling plans to 2014 at the earliest). Sean Churchfield, Shell's operations manager in Alaska, told the hearing that work needed on the Kulluk included the replacement of cranes.

Although Shell has said that the timing of the rig move was mainly determined by the need to complete the maintenance work in good time for the 2013 drilling season, Churchfield told the hearing that Shell had wanted to move the rig out of Alaska before the end of the year to avoid having to pay state property taxes for the rig — taxes are based on a company's inventory in the state on Jan. 1. However, according to a February Associated Press report, state officials have said that, as a drilling vessel operating outside state waters, the Kulluk would not have been assessed state taxes.

Norman Custard, Shell's team lead for emergency response in Alaska, told the hearing that the tow had been expected to take 18 to 24 days and that no one had forecast seas in excess of 30 feet during the period of the tow. Marc Dial, a tow master with Offshore Rig Movers, who had been in charge of the tow of the Kulluk north to Dutch Harbor in June 2012, testified that a winter transit through the Gulf of Alaska could be conducted safely.

Crew on board

But why did Shell have a crew of 18 on board the Kulluk during the winter tow? During the first day of the hearing Custard testified that a prime concern from the outset of the towing incident had been the safety of the crew and the need to evacuate the crew from the drilling rig.

Dial said that Shell's warrantee surveyor who had examined the towing system

see KULLUK HEARING page 11

continued from page 10

KULLUK HEARING

for the company's insurance underwriters had insisted that a crew needed be on board the Kulluk.

According to Capt. Jon Skoglund, master of the Aiviq, the requirement to have a crew on the Kulluk caused Noble Drilling Corp., the company providing the crew, to insist that the tow take a route relatively close to the coast, rather than a direct route across the middle of the Gulf of Alaska. Noble wanted a route that would enable the evacuation of crew members from the Kulluk, if necessary, Skoglund said. In the event, following the failure of the tow with the Aiviq, the Kulluk's crew had to be evacuated by Coast Guard helicopter.

But the direct, more southerly route across deep water would have lessened the risk of a grounding and would have allowed the use of a longer tow line, with the long line sinking deep into the sea to absorb buffeting from rough weather, Skoglund testified.

Towline parted

Todd Case, a Noble rig manager, testified that at the time when the tow line parted on Dec. 27 the Kulluk had been moving slowly over giant, long swells and had not been pitching or rolling violently. Bobby Newill, the Aiviq's third mate, described the weather as "moderate" at the time of the tow failure.

Case commented that he thought that there should have been two tugs, rather than just the Aiviq, conducting the tow. But Rodney Layton, captain of the Alert, a tug that assisted the Aiviq in trying to pull the Kulluk to safety on Dec. 31, described the hazards of using two tugs in heavy seas, with the two vessels operating in relatively close proximity and coming off swells at different times.

It is clear from testimony presented at the hearing that the tow parted because of the failure of a large shackle used to connect the towline to the Kulluk's tow gear. But, with the shackle now lying on the seafloor somewhere in the Gulf of Alaska, it is unlikely that anyone will ever establish whether the shackle broke, or whether the cotter pin that closed the shackle simply came out, releasing the towline.

Shackle inspected

Anthony Flynn, an oil and gas technical consultant with GL Noble Denton, was Shell's warranty surveyor for the tow. Flynn testified that he had inspected the shackle prior to the tow and that at that time the shackle's cotter pin had been in place. The tow master, a Shell representative, an engineer and others had all inspected the tow gear, Flynn said.

Apparently the shackle had a 120-ton rating, a rating higher than the 85-ton rating specified in the Kulluk tow plan. According to an Associated Press report on the Coast Guard hearing, William Herbert, under contract with Shell from Delmar Systems Inc., had also inspected the shackle prior to the departure of the Kulluk from Dutch Harbor and had found the shackle to be in good condition. Herbert said that the 3-inch diameter towline, with a breaking strength of 85 tons, should have broken rather than the shackle, should the tow system have been subjected to excessive stress.

Slime in fuel

The multiple engine failure in the Aiviq on Dec. 28 appears to have resulted from the clogging of the engines' fuel injectors by a slimy material in the fuel, according to testimony by Carl Broekhuis, the Aiviq's chief engineer. Broekhuis said that he suspected that a fuel additive had caused the problem. However, Coast Guard investigator Keith Fawcett when questioning Skoglund, the Aiviq's captain, commented on a common practice of adding biocide to vessel fuel to prevent the formation of algae and slime. Skoglund said that he was not aware of any biocide being used to treat the Aiviq's fuel tanks.

The Coast Guard has taken samples of the Aiviq's fuel for analysis but has not yet published the analysis results.

Apparently the Aiviq was carrying spare fuel injectors but, nevertheless, had to obtain additional injectors to restore engine operations, using fuel from an uncontaminated tank. Edison Chouest, the company owning the Aiviq, had flown the additional injectors to Kodiak in the company owner's private jet, with the Coast Guard then delivering the injectors to the Aiviq, Broekhuis said.

During the hearing the Coast Guard indicated that it anticipated publishing its inquiry report in early July but the agency has since said that the publication date will be delayed. ●

The Anchorage Daily News contributed to this story.

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GOVERNMENT

Parnell signs Flint Hills royalty oil bill

Alaska Gov. Sean Parnell has signed legislation extending state royalty oil sales to the Flint Hills Resources refinery at North Pole, near Fairbanks.

Parnell signed Senate Bill 86 into law during a June 11 visit to the refinery.

"Extending the state's contract with Flint Hills Refinery is good for the Interior and good for Alaska," Parnell said in a press release. "Many industries across Alaska rely on the fuels that Flint Hills produces, and the extension of this contract will keep Alaska's economy growing."

Passed unanimously

The Alaska Legislature passed SB 86 unanimously. Legislative approval was required to execute the new five-year contract the Parnell administration had negotiated with Flint Hills.

The contract will follow an existing 10-year contract that expires on March 31, 2014.

Under the new contract, the state will supply 18,000 to 30,000 barrels per day of royalty crude to Flint Hills.

Royalty oil is the state's share of the oil that companies produce from leased, state-owned land. The refinery draws North Slope crude from the trans-Alaska pipeline, which passes nearby.

The North Pole refinery is the state's largest, producing predominantly jet fuel. Flint Hills is a subsidiary of Koch Industries Inc. of Wichita, Kan.

—WESLEY LOY

● GOVERNMENT

Beaudreau hears Arctic drilling views

BOEM chief Tommy Beaudreau in Anchorage for 'listening session' on rules Interior should put in place for Arctic OCS drilling

By LISA DEMER
Anchorage Daily News

Against the backdrop of Royal Dutch Shell's troubled 2012 attempt to drill in the Arctic Ocean, a top Interior official — and former Alaskan — heard the gamut of views June 6 about whether and how oil companies can safely drill offshore in the Alaska Arctic.

No drilling at all, said the Sierra Club.

Clear and consistent standards, said the oil companies and industry groups.

The Department of the Interior for the first time is crafting specific rules for oil and gas exploration and production offshore in the Arctic. While Shell was operating under special conditions, such as a ban on drilling into oil-rich zones without a spill containment system, those requirements don't automatically extend to other oil companies.

Beaudreau led critical review

Tommy Beaudreau, director of the Bureau of Ocean Energy Management and the department's acting assistant secretary over land and minerals management, earlier this year led a critical review of Shell's 2012 drilling season about which then-Interior Secretary Ken Salazar concluded, "Shell screwed up."

"Our report says going forward we should have in the regulations additional Alaska-specific standards for operations offshore in this state," Beaudreau told 50-plus people gathered in the Assembly chambers at Loussac Library for a listening session intended to help the department craft new rules.


TOMMY BEAUDREAU

Beaudreau told the audience he still felt a connection to Alaska, where his family moved in 1979. He remembers when Loussac was built and wondered if it had more books now. For a time, his father worked on the North Slope, two weeks on, two weeks off. Beaudreau was a junior at Service High School during the Exxon Valdez oil spill.

"That made, obviously, a huge personal impression on me," Beaudreau said. "So I also understand that perspective of things — problems, the disruption, the harm that can be caused when oil and gas activity goes wrong." A lawyer, he landed at the Department of the Interior in 2010, two months after BP's deadly Deepwater Horizon blowout in the Gulf of Mexico.

Now he's overseeing the rules to ensure safe drilling here.

Shell, Conoco want consistency

Beaudreau and other federal officials heard June 6 from Shell, which has canceled plans for drilling this year, and ConocoPhillips, which has put off its Arctic offshore drilling because of uncertainty over standards. Environmentalists, representatives of the North Slope Borough and the Northwest Arctic Borough and concerned individuals spoke up too.

Some highlights:

• Shell's Lucas Frances said the company has long advocated for "clear, predictable, consistently applied rules." Shell, the biggest leaseholder offshore Alaska, supports high standards, but the federal government also needs to allow room for innovation and not tell operators how to solve all the issues, he said. Companies shouldn't be instructed to be good neighbors — that's essential and will happen anyway, he said.

Shell, one of the biggest oil producers in the world, last year experienced a grounded oil rig, another rig that dragged anchor, equipment issues on both rigs, and engine failures on a tow ship — and that's without tapping into oil-producing rock.

• Mike Faust of ConocoPhillips said the company expects clear and reliable standards that won't change during exploration and development. And like Shell's Frances, Faust said the federal government should craft "performance standards" but not prescribe particular technology or equipment.

Wilderness Society cites challenges

• Lois Epstein, Arctic program director for The Wilderness Society, said Shell's troubles illustrate the challenge of Arctic drilling. The new rules need to go beyond the requirements put on Shell, she said. Among the dozen items on her list are polar class oil rigs, Arctic-engineered pipelines, standby rigs to drill relief wells in case of a blowout, well-capping and containment systems, and zero discharge of drilling mud and other waste at sea.

• Daniel Lum of Fairbanks, who grew up in Barrow, told Beaudreau that his agency isn't giving the public enough time to comment on oil company permits before they are issued. When permits limiting air pollution from rigs were under the federal Environmental Protection Agency, for example, groups could challenge them through an administrative appeals process. But after Sen. Lisa Murkowski pushed to streamline the process and move air permit approvals to the Bureau of Ocean Energy Management, that opportunity vanished, he said.

"You are giving us no time frame, no opportunity for administrative appeal. Basically, you are taping our mouth shut," Lum said.

Borough questions exclusion

• Kenny Gallahorn, an official with the Northwest Arctic Borough, questioned why the borough was excluded from the formal community consultation process. Even though his region doesn't border the drilling areas, marine mammals hunted by borough residents cross borough lines, he said. Beaudreau said later the community may need to be directly brought into the process.

• Rick Rogers, executive director of the Resource Development Council, noted that years ago 30 wells were drilled in the Beaufort Sea and five in the Chukchi Sea "without incident." Technology has only improved since then, he said.

• But Tom Lohman, environmental resource specialist for the North Slope Borough, noted that some whaling communities failed to get a whale during that earlier drilling. Last year for Shell, regulators banned drilling during whaling season.

The industry's call for performance standards doesn't make sense, Lohman said, when companies haven't demonstrated an ability to clean up an oil spill in the Arctic.

Beaudreau was scheduled to hold two additional listening sessions June 7 in Barrow. His team will go over the comments in detail, he said.

"I think what we heard here today from across the spectrum, and we did get the entire spectrum today, was a lot of passion and a lot of sincere belief and strong feeling across the board." ●

● FINANCE & ECONOMY

The ups and down of Alaska job growth

A selection of new projects are driving employment to record highs, but inherent limitations keep Alaska behind other states

By ERIC LIDJI

For Petroleum News

It can be hard to make sense of oil and gas industry employment in Alaska.

The industry has reported record employment levels almost every year since 2006 and as of April 2013 direct employment stood at a high of 14,100 jobs. But the steady increase in jobs came as oil production fell just as steadily over the same time period. The rise in employment generally followed a similar rise in oil prices, except that a sharp drop in oil prices during the early days of the recession barely dented the steady growth in employment.

For all its economic power, the core industry comprises just 4 percent of statewide employment. Alaska is currently responsible for some 8 percent of total domestic oil production, but employs less than 3 percent of all U.S. oil workers. And while oil industry employment is growing in Alaska, it is growing slower than in other states.

A new analysis from the Alaska Department of Labor and Workforce Development suggests these discrepancies are systemic, resulting from two factors unique to Alaska: exceptionally large fields located in an exceptionally remote corner of the country.

These factors undermine what has appeared to be a neck-and-neck tie between Alaska and North Dakota industry employment, and suggest North Dakota will almost certainly be home to many more jobs than Alaska as the oil industry there begins to mature.

A few big fields

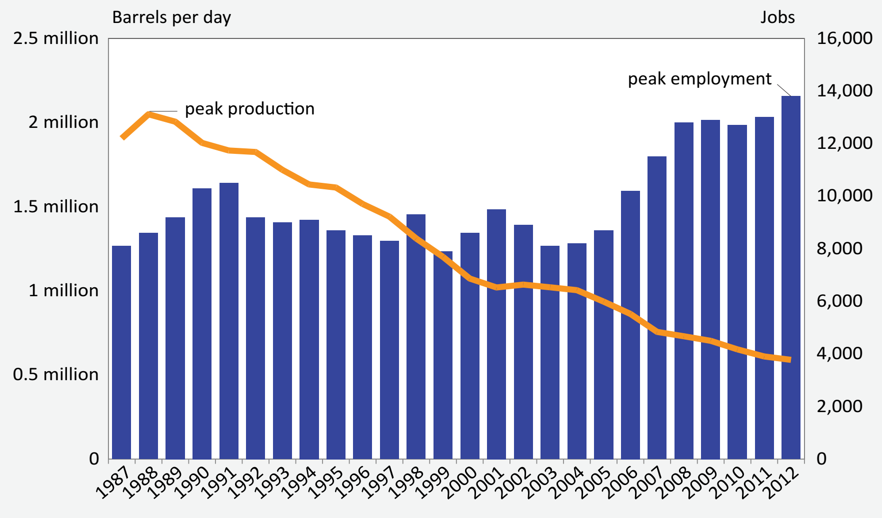
Bigness built the Alaska oil industry.

The discovery of the Swanson River field in the Cook Inlet basin helped secure statehood for Alaska and the discovery of the mammoth Prudhoe Bay field on the North Slope a decade later gave the young state the financial wherewithal to ensure it could survive.

With the industry focused largely around a single large field in its early years, employment boomed and busted based on the life of Prudhoe Bay: swelling during the construction on the trans-Alaska oil pipeline and shrinking after the project was done.

2 More Jobs Despite Production Decline

Alaska oil production and employment, 1987 to 2012



Sources: U.S. Department of Revenue; and Alaska Department of Labor and Workforce Development, Research and Analysis Section

ALASKA DEPARTMENT OF LABOR AND WORKFORCE DEVELOPMENT

All fields require a certain number of workers for basic tasks, and as such a large field typically employs fewer people per barrel than a small field, according to the analysis.

Even though the industry has brought several fields online in the decades since discovering Prudhoe Bay, they have all been large by industry standards. By some counts, 10 of the 50 largest oil fields in North America are on the North Slope.

The current increase in employment can largely be attributed to new activity from Pioneer Natural Resources, Eni Petroleum, ExxonMobil, Shell and the many smaller companies in Cook Inlet, but even with all those new fields and all that new exploration, Prudhoe Bay still accounts for some 45 percent of total state oil production.

By comparison, most oil producing states have a mix of field sizes, including stripper wells that produce less than 10 barrels per day, but still require some employment.

In states where smaller fields are economic, the industry is less consolidated.

Some 117 oil and gas establishments called Alaska home in 2011, and only a handful of those actually drilled wells. By comparison, Louisiana had 1,788 establishments that year. And Oklahoma, a state with less than half as much production as Alaska, had 3,092.

Marginal economics

The problem is geography.

"If Alaska's oil fields were not as remote, employment would be considerably higher," Department of Labor Economist Neal Fried wrote in his analysis. "Oil fields considered marginal or not economically feasible would be economic if they were less remote."

This remoteness impacts the Alaska oil industry in other ways, too.

For instance, Fried notes, most oil and gas industry jobs in Alaska exist solely to produce oil and gas in Alaska, whereas many industry jobs in Texas, Oklahoma and Louisiana involve management and research for big companies working in other states or countries.

This is why Texas employs 17 times as many oil industry workers as Alaska, even though the state is responsible for only four times as much oil production as the Last Frontier.

And because Alaska is so far from the markets it serves, the industry is primarily an upstream endeavor. The few long pipelines snaking across the North Slope and the single pipeline down through the state to Valdez barely compare to the thousands of miles of pipelines crisscrossing the Lower 48, and the handful of Alaska refineries mostly serve local needs.

In 2012, the six Alaska refineries handled 385,000 barrels of oil per day, while the 19 Louisiana refineries handled 3.2 million barrels per day, 2.5 times as much per facility.

The remoteness impacts the workers, as well as the work. The non-resident workforce in the Alaska oil industry has hovered between 26 and 31 percent for a nearly a decade.

Look out for North Dakota

For these reasons, North Dakota employment could soon pull far ahead of Alaska.

As of 2011, the North Dakota oil industry produced some 242 million barrels of oil and employed 14,926 people, some 15 to 18 percent higher than Alaska figures that year.

The 37 percent job growth in the Alaska oil industry in the past decade is good for the state, but well below the 62 percent growth in the industry nationally, although still above Louisiana and California, two other states where production fell over the past 10 years.

But those states also have established industries. In North Dakota, oil industry employment jumped 557 percent over the past decade, as improved technologies opened up previously uneconomic formations and companies began leasing land and drilling wells.

These technologies have also boosted oil production in Texas and natural gas production in Louisiana, but have yet to impact Alaska production to any considerable degree.

A source rock development such as the one being pursued by Great Bear Petroleum could bring those increases to Alaska, but whether and when it ever will remains unknown. ●

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INTERNATIONAL

Statoil cites tax issues in project delay

Norwegian oil company Statoil has announced that it is delaying an investment decision for its Johan Castberg oil field in the Barents Sea because of a combination of uncertainty in the resource estimates for the field and proposed changes to Norwegian petroleum taxes. Statoil says that it has been continuing to assess the project, and that the tax changes are compounding the overall project uncertainty. The field, previously called Skrugard, lies about 240 kilometers northwest of Hammerfest and is thought to hold 400 million to 600 million barrels of oil.

According to a report in the Wall Street Journal, in early May the Norwegian government announced an increase in its petroleum tax by reducing the amount of field development cost that companies can write off against their tax liabilities. Oystein Michelsen, Statoil's executive vice president for development and production in Norway, said in a Statoil news release that the tax changes have made it necessary to review the Johan Castberg project.

"The updated project estimates and the new uncertainty in the tax framework has made it necessary to consider what consequences this may have for the development concept," Michelsen said.

Rather than gathering oil production taxes and royalties, Norway gains revenues from oil fields by maintaining a mandatory government working interest in all fields, with the government investing in the fields and taking its share of field revenues. However, the government assesses very high rates of corporate income tax on oil companies, albeit with tax deductions for expenses and investments.

—ALAN BAILEY

ENVIRONMENT & SAFETY

Court won't reconsider polar bear decision

The federal District Court in Alaska has declined to reconsider its ruling rejecting the U.S. Fish and Wildlife Service's designation of critical habitat for the polar bear.

Following the listing of the bear as threatened under the Endangered Species Act, in 2010 Fish and Wildlife had designated a critical habitat area amounting to 187,157 square miles, including much of Alaska's Arctic offshore and a broad swath of land around the Beaufort and Chukchi Sea coasts. A group of organizations, including the Alaska Oil and Gas Association, the Arctic Slope Regional Corp., the State of Alaska and the Inupiat Community of the Arctic Slope appealed the designation in District Court.

The organizations fear that the habitat designation would unnecessarily restrict commercial and subsistence activity in the Arctic.

On Jan. 11 District Court Judge Ralph Beistline issued a ruling placing the habitat designation on remand. Beistline upheld the offshore habitat designation but said that the onshore designation, along the coast and on the coastal barrier islands, was much too broad, with critical habitat features only occupying a tiny proportion of the total land area.

In February the Department of the Interior asked Beistline to reconsider his decision, saying that the court had misunderstood the agency's specifications of the features that define the onshore critical habitat.

In a court order issued May 15 Beistline denied the request to change his January decision."While great effort was expended to study the relevant issues, the final decision to designate a land mass larger than many states does appear excessive and is not justified by the record before the court," Beistline wrote.

—ALAN BAILEY

continued from page 7

ANWR STANCE

Murkowski and the others have been pushing BLM to clean up the legacy wells, and are upset that the president's 2014 budget proposal included language that would divert the state's share of NPR-A oil and gas revenue to pay for legacy well cleanup.

The senator says that's unacceptable, that it falls solely on the federal government to clean up those wells.

"Is it your opinion that the state of Alaska should be held financially responsible for the federal government's responsibility to remediate these wells?" Murkowski asked Jewell.

"I completely agree that the legacy wells are a problem that we need to solve," Jewell replied. "They do need to be cleaned up."

But Jewell said the USGS and Navy drilling was "one of the reasons we have a sense of the resource potential" in the NPR-A.

She noted that BLM recently released a legacy well assessment and priority list for cleaning up the worst of them.

"We do need money to be able to do that," Jewell said. "And, you know, I would like to think that as the resource was assessed in part through the use of these wells, that the revenue from the resource — state and federal — be used to help in the cleanup. I think that it is a revenue generator, it puts oil in the pipeline. We need to work on figuring out how to pay for it. Because right now, there isn't sufficient money."

"I would agree that we have some very difficult budget limitations. We all know that," Murkowski responded.

"I want to work with you on a path," she told Jewell. "But if that path is going to mean that monies that would be going to the state of Alaska and the residents of the North Slope are going to be choked back, that's not appropriate." ●

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continued from page 1

NEW ENCANA BOSS

the company.

"I want to do that once and I want to do it right," he said, making it clear that disclosure of the details will have to wait until second-quarter results are released in July.

He told analysts that a mid-year review "may decide to reallocate capital among programs" once he has determined how Encana is "currently performing in each of its key areas."

"I hope you can appreciate that it will take some time before I'm in a position to articulate a clear and concise vision for Encana," Suttles said.

"In the meantime, Encana will maintain its purpose of delivering on the 2013 budget plan," including a "heightened focus on capital discipline and improving efficiency."

The conference call yielded only two questions, once of which was answered by incoming chairman Clayton Woitas, who said there has been no discussion among directors about changing the company's divided.

Suttles has been placed by analysts in the same category as new leaders at Suncor Energy, Talisman Energy and Penn West Petroleum in lowering operating costs and attracting investors back to flagging stocks.

During his time with BP he was assigned to Alaska, the North Sea, Trinidad and Sakhalin, Russia, and headed BP's response to the Deepwater Horizon oil spill in 2010.

Cuts already announced

While the search continued over the past six months for a new CEO, Encana announced plans to cut up to US$150 million in general and administrative costs, with Woitas targeting an additional 10 percent improvement in the "company-wide average capital and operating efficiency number."

He said Encana is "first and foremost a natural gas company and we're striving to regain our reputation as the lowest-cost and most efficient developer of natural gas. Encana already has low cost structures in many of its plays, but the status quo is not an option."

Encana, which has been campaigning for the use of natural gas as a transportation fuel, has also been targeting an increase in its natural gas liquids production to about 75,000 barrels per day by the end of 2013 from a current 43,000 bpd. Its first-quarter gas production was down 12 percent year-over-year at 2.88 billion cubic feet per day. For 2014, it has hedged 1.5 bcf per day of output at US$4.19 per thousand cubic feet.

In the past year, Encana shares have dropped 10 percent, in contrast with mid-size producer such as Tourmaline Oil (up 70 percent), Peyton Exploration (up 77 percent) and Paramount Resources (up 42 percent).

—GARY PARK

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continued from page 3

PARNELL Q&A

Petroleum News: Do you have any timeline to offer?

Parnell: You've seen me lay it out very clearly in my State-of-the-State address. You can look at the 2012 benchmarks I set that were met. Now 2013 has two benchmarks that come due here very quickly. One benchmark was that they would conduct a full summer field season. The second benchmark was they would complete a pre-FEED commercial agreement, that's a pre-front end engineering and design.

That pre-FEED is not sanctioning a $30 billion project. That's not what that part is. That pre-FEED commercial agreement is the companies' commitment to move forward on hundreds of millions of dollars of work related to pre-front-end engineering and design.

My design in putting in that benchmark is to bring the companies to a commensurate level of monetary commitment that the state has made under AGIA and with AGDC. The companies are spending tens of millions of dollars now; I want them committing to hundreds of millions in this next phase, known as pre-FEED in the industry.

That's the commensurate proportionate step. If you read the words in my state-of-the state address very closely, it talks about "by spring." Well as you know spring is a three-month period ending about June 20, so we'll know very soon whether they are going to meet the benchmark of a full summer field season and the benchmark of a pre-FEED commercial agreement.

Petroleum News: For the next legislative session what would you like to be doing for the natural gas line?

Parnell: I'd like to see the companies moving forward with their pre-FEED commercial agreement. I'd like to see AGDC moving forward under its statute sharing information. The bottom line is we've got to get another summer field season in. We've got to get these parties aligned with a commercial agreement. And if not, the state has to continue its course in building our own.

Petroleum News: Resource Energy Inc. made some news about a completed feasibility study. Could this represent a buyer becoming a direct investor? What are your thoughts about this development out of Japan?

Parnell: Don't think that was done in a vacuum. We signed an MOU (memorandum of understanding) with them months ago to accomplish just this. I met with their leader in Japan. Commissioner (Dan) Sullivan has had multiple meetings with them. In fact Commissioner Sullivan met with them before I went to Japan and Korea. We've been working with them and providing information under the MOU for quite some time now.

Certainly, they are doing just what we asked: presenting their findings to the state and presenting their findings to the producers who are involved in building the line. The producers have worldwide gas marketing organizations. The companies like REI and others, they represent investors in liquefaction facilities, in leases, in gas treatment plants, and we certainly are looking at all options.

Petroleum News: Staying with the prospect of export, do the discussions in Washington limiting export, does that concern you? Do you feel at all hamstrung?

Parnell: It concerns me only because they might unknowingly lump Alaska into that category. I think we are uniquely situated. The concerns expressed in Congress where (Democratic Massachusetts Rep. Edward) Markey wants to prohibit LNG exports really has to do with gas supply issues and demand issues in the Lower 48. Of course Alaska's gas doesn't play in that market.

My argument is Alaska should be treated differently because Alaska's gas doesn't impact the price of Lower 48 gas. Our unique situation bodes well for getting approval for an export license. I think the federal administration has to be hungry for a win in the energy sector. Approving an export license for Alaska would be significant win for them and it would not hurt or affect Lower 48 consumers' supply or demand, which is what Congress has expressed its concerns.

Petroleum News: Cheniere has an export permit approved and there are 19 permits under consideration — of course, not all are expected to be approved or even pursued toward approval. With all of that activity in the Lower 48, is that a problem for Alaska?

Parnell: Not right now. Like I said, I think we're uniquely positioned. We have 40 years of dependable shipments from Nikiski from Marathon and ConocoPhillips, and because shipments don't affect supply and demand for the Lower 48. And finally, looking at it from the international perspective and demand side, companies from countries like Japan and Korea also like a diverse supply. They don't just want one supplier. They will buy gas from Australia, from the Gulf, from Alaska or from Canada if they could get it. They take ships from all over. It helps from their perspective, they like that diversity of supply not having to rely on one customer.

Petroleum News: There are a lot of deals going on in the Asian market, especially out of Australia. Is that window of opportunity closing, as some have said?

Parnell: The window of opportunity argument is specious and made by those who want to stampede others into a deal. Market windows don't close. Market windows change. One closes and one opens. Just a few years ago, there were 42 applications for LNG import facilities in the U.S. Now look. It's flipped. And so the opportunity to market our gas has moved from a pipeline to the Lower 48, to what we have today, movement toward an LNG export facility in Alaska while providing for Alaskan communities. People who make that lost opportunity argument are usually trying to stampede someone else into making a deal. It's not in the state's interest to be stampeded. It's in our interest to perform our due diligence, and move proactively and quickly. I don't buy this window of opportunity argument. ●

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GOVERNMENT

AOGCC looking for technical support

The Alaska Oil and Gas Conservation Commission has issued a request for proposals for petroleum measurement technical consulting support.

AOGCC has a statutory requirement to regulate measurement of oil and gas and has adopted regulations requiring operators to measure production in accordance with the American Petroleum Institute Manual of Petroleum Measurement Standards revised as of Nov. 30, 1998.

But the API manual is "a living document" and many sections have been added and/or revised more recently than the version adopted by AOGCC. With new developments in Alaska and aging equipment in existing fields, AOGCC has received a large number of applications to install or alter custody transfer measurement equipment and facilities for well testing and allocation purposes, burdening the agency's staff.

To alleviate that burden AOGCC proposes to contract with an expert in petroleum measurement.

The primary component of the RFP is to review petroleum measurement applications from operators and make recommendations to the commission on whether to approve them or require modifications. The commission also wants a guidance document prepared specifying information required in applications and development of petroleum measurement system inspection guidelines for use by AOGCC staff.

A review of current industry petroleum measurement standards will be required — with recommendations on standards the commission should require and proposed revisions to the commission's regulations to bring them up to date, and training for AOGCC staff in some of the newer technologies being used in the industry.

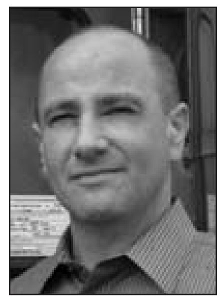
The length of the contract is one year with two optional one-year renewals. The agency's budget for the work is between $200,000 and $750,000. Proposals are due June 24 and the contract is scheduled to start July 10.

—PETROLEUM NEWS

Petroleum news

Oil Patch Bits

Skinner promoted to VP of Freight Services



BRIAN SKINNER

Sourdough Express said June 6 that Brian E. Skinner has been promoted to vice president of Freight Services.

Skinner joined Sourdough Express 10 years ago as the manager of business development. He was quickly promoted to general manager as his leadership increased a loyal customer base and successfully diversified the services Sourdough Express provides.

As VP of Freight Services, Skinner will lead Sourdough Express to new growth, while keeping the unparalleled customer service reputation Sourdough Express has sustained for over 100 years.

Sourdough Express is a full service trucking company servicing Alaskans since 1898.

SANY America names Totem its Alaska excavator dealer

Totem Equipment & Supply said June 4 that it has been named the first SANY America excavator dealer in Alaska, representing SANY in the Anchorage market.

"There is a lot of opportunity in Alaska and we're excited to partner with a company that has found the key to success for over 50 years," said Eric Teague, vice president of earthmoving at SANY America. "Totem is another family-owned success story with a dedicated heritage of trust, dependability and customer service. We look forward to a great partnership."

"We heard a lot of good things about SANY and when I visited their operations in Georgia I knew it was a good fit for us," said Totem owner Mike Huston. "They listen as a company and their product is solid. We like that they use name-brand components and that the product will lend itself well to the cold, rough conditions we often face here in Alaska. We're glad to get in on the ground-floor as one of the initial dealers for SANY."

Totem Equipment & Supply was founded in 1961 by Cliff Huston and his wife and business partner Allie Huston. Today under the ownership of Mike Huston, the family business continues to thrive as Alaska's leading equipment distributor and full-service rental company.

SANY is a global leader in the manufacture and sale of hoisting, concrete machines, road machinery, port equipment, excavators, mining equipment, pile-driving machinery and wind turbines.

M-I SWACO introduces new dual-deck shale shaker

M-I SWACO, a Schlumberger company, said June 6 that it has introduced the MD-2 dual-deck shale shaker. When combined with DURAFLO composite screens, the MD-2 shaker provides optimal solids control performance for drilling applications.

see **OIL PATCH BITS** *page 17*

Companies involved in Alaska and northern Canada's oil and gas industry

All of the companies listed above advertise on a regular basis with Petroleum News

continued from page 1

'BOIL-OFF' GAS

the companies finish building the interconnection facilities required to move the gas into the existing system.

The RCA is taking comments of the agreement through July 5.

Small, but useful

The volume of sales depends on the amount of gas available and the amount of demand in the Enstar distribution area within a given time, but the companies expect both the plant to produce and the system to demand some 900,000 cubic feet per day on average.

The boil-off gas would provide only a small supply, but it could come in handy on those extra cold days when every bit counts. For comparison, the 300 million cubic feet per year in boil-off gas would supply less than 1 percent of the total Enstar annual demand.

For ConocoPhillips, the agreement provides a way to earn revenue from the LNG plant, which was pioneering when it came online in the late 1960s, but has recently suffered from uneven supplies locally and uneven demand from its traditional customers in East Asia. The future of the facility is currently uncertain. ConocoPhillips recently chose not to request another extension of the export license required to ship volumes overseas.

The boil-off gas will serve as an interruptible supply, and either party would be allowed to terminate the agreement at any time and for any reason except to chase a better price.

The gas would be priced using the mechanism in an existing base gas contract between ConocoPhillips and Chugach Electric Association, which came to $3.46 per thousand cubic feet in the second quarter. The mechanism has the benefit of having already received RCA approval.

Chugach recently asked the RCA to approve the agreement, saying the deal "maintains the readiness" of the LNG plant, which in turn "preserves locally produced LNG as an option for excess gas that is discovered, either for export or to help meet local needs."

ConocoPhillips is reimbursing Enstar for the cost of the interconnection facilities.

Because the boil-off gas is produced at low pressure, it is only appropriate for use in the distribution system and cannot be injected for underground storage, according to Enstar.

—ERIC LIDJI

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continued from page 1

BC LNG PROJECTS

In addition to helping companies such as Chevron, Shell, Petronas and British Gas negotiate sales commitments, Clark has many hurdles to clear — an unclear long-term demand for LNG in Asia, the reluctance of prospective Asian customers to entertain oil-indexed pricing, the looming threat of environmental and First Nations opposition, and the absence of a clear strategy by government-owned BC Hydro to provide the power to serve LNG facilities.

The Liberal government, re-elected May 14 in a staggering come-from-behind victory, will also include Bill Bennett as minister of energy and mines, along with presiding over a core review of government spending.

Clark's cabinet selections coincide with warnings over rising LNG capital costs, the lessons to be learned from Australia's challenges, and the competition between LNG proponents and others who have their sights fixed on using Western Canadian gas for transportation, industrial uses and oil sands production.

Ally in Enbridge

However, she has found an unlikely ally in Enbridge, which said in its final submissions to regulators handling the Northern Gateway application that if the pipeline is built it could attract C$18 billion in oil and gas investment, providing a "ready source of capital ... (for) the development of a British Columbia LNG industry."

Northern Gateway President John Carruthers said it needs to be understood that higher netbacks for oil producers as a result of Northern Gateway can underpin "more and more activity, including natural gas."

Kevin Petak, vice president of gas market modeling for ICF International in Fairfax, Va., said the window of opportunity for LNG exporters will remain open for only a decade.

He told a Canadian Energy Research Institute conference in Alberta that competition from Australia and North Africa could limit the United States and Canada to serving 30-40 percent of global LNG demand.

Steve Lewandowski, a senior director for global ethylene with IHS Chemical, issued a blunt message.

"The dithering about LNG projects in British Columbia has to stop," he said.

Although British Columbia is closer by sea to China than the U.S. or Australia and its colder climate makes the liquefaction process more efficient, uncertainty stems from fracturing regulations, carbon taxes and the question of how much LNG can be tied to oil prices, Petak said.

He said the 2015-25 period will likely be one of rapid expansion when sources of market growth come together, but construction cost pressures could limit the number of projects that get an investment go-ahead.

Rising gas prices forecast

ICF forecasts that Henry Hub natural gas prices will be US$4 per million British thermal units through to 2015, then rise to US$5-$6, driven by market growth, while Western Canadian prices are likely to be 50 cents to $1 lower.

At the same time, North American shale gas production is expected to almost double to 65 billion cubic feet per day by 2025, with Marcellus production adding another 20 bcf per day by 2025.

ICF offers a "middle of the road" estimate of 526.6 trillion cubic feet of gas resources in the Montney, Horn River, Cordova Embayment and other plays, Petak said, adding that some of the newer plays have yet to be fully evaluated.

Skya Kruithof, senior commercial manager for petrochemical feedstocks at Dow Chemical Canada, said LNG exports could also be positive for his industry by opening the way to liquids extraction from the gas, although the lack of infrastructure in the gas-liquids areas could pose challenges.

Gerry Goobie, a principal with Gas Processing Management, said companies that plan to build grassroots LNG export facilities in British Columbia have yet to estimate how much gas prices could rise, but he agreed with Petak that a marginal increase would spur renewed drilling activity in British Columbia and Alberta.

"You will be amazed at how many producers will be chasing that kind of margin," he said.

Petak forecast that about 134 percent of total gas produced in Western Canada by 2025 will be used by LNG operations.

High costs similar to Australia

At a Calgary forum Samantha Santa Maria, Platts managing editor of natural gas, said Canada should look "really carefully" at what happens in Australia because the two countries have high costs, especially labor, and need "oil indexation at some point in their pricing formula."

She said the Canadian and provincial governments must work with various stakeholders such as First Nations to ensure the infrastructure that is needed can be constructed cost effectively, but added the "availability of labor is a real concern."

Because China is ramping up its shale development its need for LNG may start to decline, making it critical to get LNG projects operating by 2020 at the latest, Santa Maria said.

She suggested the British Columbia projects that have the best chance of "getting off the blocks" are the BC LNG Export Cooperative, with the recent addition of Golar LNG, to export up to 700,000 metric tons a year starting by late 2015 or early 2016; Kitimat LNG, whose operator Chevron is a "very reputable player with lots of experience in LNG markets"; and Shell Canada's LNG Canada partnership whose Asian owners have a "real vested interest in taking that gas to their market."

Also competing for Western Canada's shale gas supplies are the industrial sector and the oil sands.

see **BC LNG PROJECTS** *page 18*

continued from page 16

OIL PATCH BITS

The development of the MD-2 shale shaker was the result of customers' requests for a durable mid-range shaker suitable for both onshore and offshore applications. M-I SWACO developed the dual-deck shale shaker using the proven design of the offshore-suited MD-3 triple-deck shaker, and also utilized design elements from the onshore-suited MONGOOSE PRO shale shaker. Design validation for the MD-2 shaker was conducted at the SWECO manufacturing facility in Florence, Ky.

In a field trial in South Texas a customer was drilling a 22-inch hole using two conventional shakers, but due to capacity limitations there was a low rate of penetration. To optimize the solids control performance, one MD-2 shaker was provided, which processed drilling fluid at a rate of 658 gallons per minute, or more than twice the two conventional shakers combined. Additionally, the MD-2 shaker handled 100 percent of the flow throughout the top hole section, thereby maximizing flow rate and maintaining the desired ROP.

The small footprint of the MD-2 dual-deck shale shaker makes it ideal for space-restricted onshore and offshore drilling rigs where high-capacity separation efficiency and operational flexibility are needed. For more information visit www.slb.com/md-2.

continued from page 17

BC LNG PROJECTS

Team effort

Allan Wilms, commercial west vice president of Parkland Fuels Corp., said a team effort is already under way to gain access to LNG.

Parkland recently announced a branded distribution agreement for LNG with Shell Canada for commercial and industrial customers in various high horsepower markets, including oil and gas exploration, well stimulation applications and off-grid power generation.

Among the lengthening list of potential LNG users, Encana is counting on oil and gas companies being the "first and fastest" adopters of LNG for their daily operations; the Canadian Natural Gas Vehicle Alliance expects gas to underpin transportation; Royal Dutch Shell said LNG is a better fuel for trucking, the marine sector and rail than diesel because it is cleaner burning; and Irving Oil is talking about offering LNG at its fueling stations between Montreal and Halifax.

The oil sands sector is also in the thick of the chase for new gas production, needing an estimated 1 billion cubic feet per day for every 1 million bpd of incremental output. ●

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continued from page 1

PIPELINE EFFICIENCY

with each pipeline separately managed, with its own tariff and rate structure, the pipelines tend to vie with each other for business despite the fact that they combine to form an integrated Cook Inlet gas transportation network.

In response to requests by businesses shipping gas on the pipelines, Hilcorp is evaluating improvements to its pipeline system, including the practicalities of managing all four pipelines, in effect, as a single line, Jaroch said.

"Today the markets have changed. Some of the customers have changed. The owners have changed … This is probably a good time to do this evaluation," he commented.

Four-phase process

Hilcorp's pipeline evaluation is now in the second phase of what could become a four-phase process, Jaroch said.

Phase one, which has already been completed, consisted of Hilcorp's own internal evaluation, identifying ways in which the management and operation of the pipelines could be improved. Phase two, in progress and planned for completion by around August, involves talking to pipeline shippers and other interested parties, presenting Hilcorp's ideas and seeking other views of what might be done. If Hilcorp then decides to move ahead with changes to the pipeline system, phase three would involve a roll-out of what the company proposes, with implementation of the proposals taking place in phase four.

Inefficiencies

The evaluation in phase one identified significant inefficiencies in the regulation and operation of the pipelines as separate entities, with each pipeline requiring its own rate case as part of the regulatory process and with each having its own administration, Jaroch said. And the significant differences in shipment rates between the different pipelines tends to drive shippers to move their gas along routes determined by fees rather than by optimum pipeline usage, thus creating congestion at certain points in the pipeline network.

Rate differences also tend to make new pipeline developments more appealing on some sections of pipeline than on others, thus discouraging a system-wide approach to prioritizing development decisions, Jaroch said.

Working gas

Another issue is the small quantity of so-called "working gas" in the pipeline system, Jaroch said. Working gas, the gas that fills the pipelines, maintains the gas pressure in the lines — the more of this working gas that is available, the more flexibility the pipeline system has in responding to changes in the rates of flow of gas into the system from gas fields and out of the system to gas consumers.

Gas shippers have to nominate in advance the amount of gas that they anticipate having to move through a pipeline, with the pipeline operator then having to juggle the needs of different shippers and adjust the pipeline operation to accommodate the actual volumes of gas that flow through the system. If plenty of working gas is available, the operator can maintain pipeline pressure within an acceptable range, as gas throughput changes, by adding or withdrawing working gas. But, if working gas is in short supply, as in Hilcorp's Cook Inlet lines, the maintenance of the gas pressure can require shippers to frequently alter their gas nominations, to ensure that the delivery of gas into a pipeline is balanced by the rate at which gas is delivered from the line.

In the Cook Inlet region this problem becomes particularly acute during the extreme fluctuations in gas demand during the winter, with shippers often having to submit gas nominations several times a day for all four Hilcorp pipelines, Jaroch said.

"That causes a great deal of discomfort and a lot of work for the accountants," he said.

Pipeline consolidation

The concept that has thus far emerged from phase two of Hilcorp's pipeline project is the consolidation of all four pipelines for operation as a single system, regulated and managed as a single entity, accepting shippers' gas nominations that simultaneously apply to all of the lines, and giving Hilcorp the discretion to decide how to move gas through the system, to make optimum use of pipeline capacity.

And the key to the establishment of an arrangement of this type would be a "postage stamp rate" for shipping gas, Jaroch said. Under a rate design of this type, Hilcorp would charge a constant per volume gas shipping fee, regardless of where in the pipeline system the gas is accepted for shipment and regardless of the shipment delivery point.

In addition to giving Hilcorp the ability to appropriately route gas through the system, a postage stamp rate would place all gas fields on an equal footing for shipping costs, regardless of field location.

"It is the thing that will make the system more homogeneous, make gas more homogeneous, in the Cook Inlet," Jaroch said.

Gas storage?

Hilcorp is also evaluating three possible ways of making more working gas available for pipeline throughput management. The company could perhaps lease space for working gas in Cook Inlet Natural Gas Storage Inc.'s Kenai gas storage facility; the company may be able to implement its own gas storage facility; or the company could perhaps pay a gas producer for a working gas service, obtaining top ups of working gas from the producer as necessary and subsequently returning the gas when not needed, Jaroch said.

Hilcorp also wants to acquire a modern Internet-based nominations system that will enable shippers to go online both to nominate gas volumes for future shipment and to obtain nomination reports. Currently, shippers have to submit nominations by email, with Hilcorp staff having to transcribe the email contents into the company's nomination system.

Tricky issues

However, Hilcorp's ideas for the future are all still in something of an embryonic state, with some fairly tricky issues that would need to be resolved before implementation. For example, the company would need to figure out how to deal with current contracted commitments for use of its pipelines, including some contracts that give some shippers priority in pipeline use, Jaroch said. In additions, gas producers with fields close to customer delivery points, and hence short gas transportation distances, would likely see their transportation costs rise under a postage stamp rate, he said.

Although the overall impact of pipeline consolidation and other improvements would be reduced gas transportation costs, passed on to gas consumers, features such as increased working gas would introduce new cost factors that would need regulatory approval, Jaroch said. Hilcorp would need to be able to recover any new costs from its shipping fees, he said.

It will be necessary for all stakeholders to work collaboratively, to develop and implement solutions with overall benefits for the Cook Inlet gas industry, Jaroch said. ●

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continued from page 1

HILCORP PENALTY

tributing to regulatory compliance issues," said an April 10 decision and order from the commission. "Since Hilcorp commenced rig work in Alaska in April 2012, AOGCC Inspectors have observed rig crews unable to perform required BOPE component tests, rig crews not trained in use of well control equipment, and rigs with missing required equipment. Hilcorp's compliance history from April through December 2012 — including this enforcement action — shows 13 separate enforcement actions of varying severity since April 2012."

The order continued: "Many of these actions were due to a failure to understand regulatory requirements. Strong evidence indicates that Hilcorp has not adequately prepared its personnel for operations in compliance with AOGCC regulatory requirements. Left unaddressed and uncorrected these and similar violations will be repeated."

Hilcorp responds

All three commissioners — John Norman, Dan Seamount and Cathy Foerster, the chair — signed the four-page order.

Hilcorp spokeswoman Lori Nelson on June 11 told Petroleum News the company had asked the AOGCC for reconsideration, but the request was declined.

The company has paid the $115,500 penalty, she said. The agency confirmed it.

Nelson provided a general statement on the commission's order, particularly the part about Hilcorp's aggressive approach:

> *The commission added that since issuing a notice of proposed enforcement action against Hilcorp, the company has performed mandatory bi-weekly BOPE tests "in an acceptable manner."*

"Hilcorp acknowledges AOGCC's decision and has taken the appropriate actions to address the issues in this matter. We continue to maintain an open and collaborative relationship with the AOGCC and all other regulatory agencies. Hilcorp's investment in Alaska's resources has certainly brought an increased level of activity to Cook Inlet, but we believe we're on the right path forward and remain committed to operating safely and responsibly."

Hilcorp is headquartered in Houston. Founded in 1989, Hilcorp describes itself as one of the nation's largest privately held independent exploration and production companies with more than 1,000 employees.

The company operates locally as Hilcorp Alaska LLC, and has quickly become the dominant player in Cook Inlet.

Hilcorp made its Alaska entry in July 2011, when Chevron announced Hilcorp would buy its Cook Inlet assets, including interests in several oil and gas fields, 10 offshore platforms, pipelines and the Drift River oil tanker terminal.

In January, Hilcorp completed a deal to buy Marathon's Cook Inlet properties.

Well plans change, BOP goes untested

The AOGCC said the number of prior violations, the need for deterrence, and the need to "trigger a substantial change in Hilcorp's approach toward regulatory compliance," factored into its decision to penalize the company.

Soldotna Creek Unit 44-33 was actually a sidetrack from a suspended Swanson River well, the April 10 order said.

Hilcorp was granted approval to drill the sidetrack on Oct. 3, 2012, and drilling commenced eight days later using Doyon Rig 1, also known as the Doyon Arctic Fox.

The drilling encountered an overpressured zone, which required the closure of the upper pipe rams to control the flow of formation fluids, the order said. Hilcorp provided notice to the AOGCC of its use of the blowout prevention equipment.

"Receipt of Hilcorp's notice initiated a review of the approved drilling permit and a request for additional information, including daily drilling reports," the order said. "In response, Hilcorp revealed that the SCU 44-33 sidetrack was started at a depth approximately 500 feet shallower than approved and the drilling mud weight was not increased prior to commencing sidetrack drilling operations as required. Hilcorp drilling reports also indicate that the drilling assembly was tripped to surface on October 13, 2012 after BOPE was used to control SCU 44-33 and re-run in the well on October 14, 2012 without testing the used BOPE components."

Regulations state that "if any BOP equipment components have been used for well control ... the components used must be function pressure-tested before the next wellbore entry."

The order said Hilcorp's failure to comply was the result of either a lack of attention to regulations, or a lack of understanding of "clearly worded expectations."

During an informal review, Hilcorp explained it didn't think its changes to the approved permit were significant enough to warrant notification to the AOGCC, the order said.

"No explanation was offered for failure to test BOPE as required," the commission said.

Corrective actions ordered

The AOGCC said it considered mitigating factors in taking its enforcement action.

Hilcorp did not act in a "willful or knowing manner," there was no injury to the public, the company didn't derive "tangible benefits" from the violations, and Hilcorp stated its commitment to correct regulatory deficiencies, the order said.

The commission added that since issuing a notice of proposed enforcement action against Hilcorp, the company has performed mandatory bi-weekly BOPE tests "in an acceptable manner."

The commission's order said Hilcorp had accepted responsibility for the violations, and was making changes.

The bulk of the $115,500 civil penalty, or $75,000, was for "the initial violation — failure to increase the drilling fluid weight prior to milling the casing window" as required in the permit to drill.

The penalty also included $7,500 for each day, Oct. 14 through Oct. 17, 2012, that the blowout prevention equipment went untested after use.

The commission also ordered Hilcorp to take a number of corrective actions. It gave the company two weeks to provide a complete root cause analysis of the violations, and to submit "a detailed written description of its regulatory compliance program."

The commission further ordered Hilcorp to "provide evidence that personnel responsible for drilling and workover rig management, and staff involved with permitting well operations ... have been trained in AOGCC regulatory requirements, including the process for making changes to approved activities." ●

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